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REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	§ § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF VISTRA CORP. ON
COMMISSION STAFF'S REQUEST FOR COMMENT

TO THE PUBLIC UTILITY COMMISSION OF TEXAS:

Vistra Corp. (Vistra) files the following comments in response to the Public Utility Commission of Texas (Commission) Staff's August 2, 2021 Request for Comments.[1] These comments are timely filed.[2]

I. EXECUTIVE SUMMARY

Vistra supports the Commission's efforts to evaluate and improve ERCOT's market design to attract and retain the dispatchable generation needed to improve system reliability. As requested by Commission Staff, here is a bulleted executive summary of Vistra's comments:

- The ORDC should be revised both to reduce the maximum price and to change the shape of the curve to achieve ORDC adders more frequently at lower and mid-level prices.
- As modified, the ORDC would be useful for reducing volatility and improving resiliency, by providing sufficient revenues to maintain and build new thermal generation and increasing the supply cushion in the market.
- Improving the ORDC would not be sufficient to attract and retain backup supply for less probable events, so an additional ancillary or reserve product should be considered.
- The Commission should avoid market design changes that create different real-time energy prices for different types of resources.
- Vistra is agnostic on the question of whether there should be mandatory participation in the DAM, but a must-offer in the DAM may be a fair exchange for

[1] Request for Comment (August 2, 2021).

[2] *Id.* (setting deadline for comments on August 16, 2021).

other changes that compensate for taking the capacity value of the resource from the resource-owner, so long as generators are able to express their commitment risks and preferences through their DAM offers.

- The Commission should focus on developing ancillary service or reliability services for firm fuel, fuel storage, and/or dual fuel capability.
- The Commission should also consider a reliability service to procure standby generation for low probability events. Any generation procured through such a service should be deployed in a way that mitigates its price suppressive impact on the energy market.
- There are natural limitations to the growth of residential demand response products. To the extent the Commission wishes to expand upon residential demand response capabilities for use in grid emergencies, the Commission should consider directing TDUs to reallocate some of their existing program dollars authorized under PURA § 39.905 towards REP-administered demand response programs.
- The Commission should make common sense revisions to the ERS program to improve its reliability benefits.

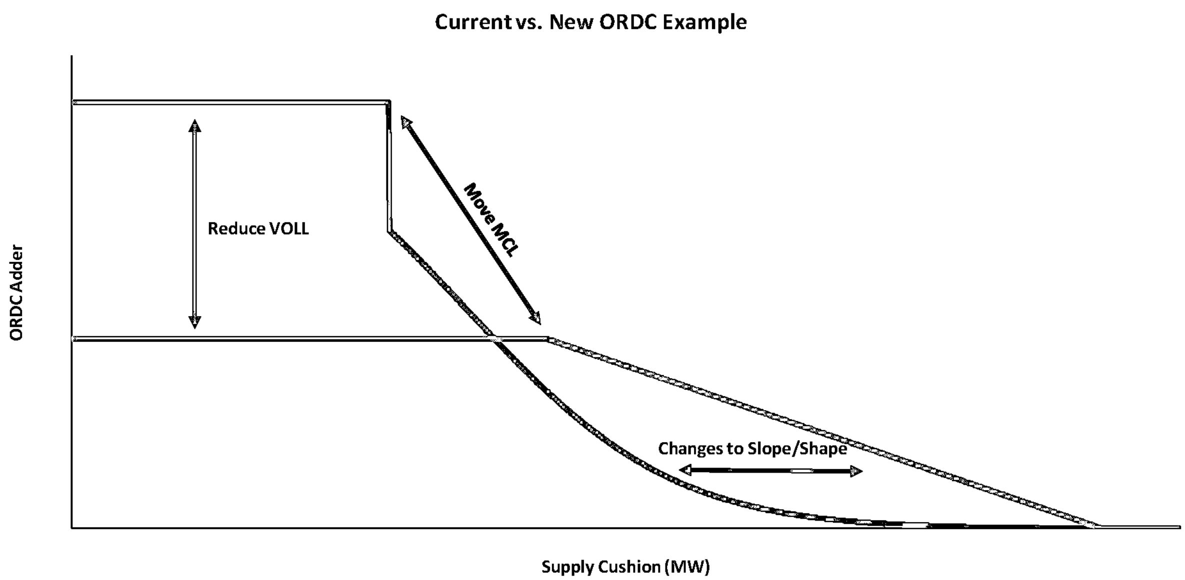
II. RESPONSE TO STAFF QUESTIONS

QUESTION 1: What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market (DAM). Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?

The Operating Reserve Demand Curve (ORDC) is an important tool in the energy market to facilitate scarcity price formation. The ORDC is a function of the value of loss of load (VOLL), which sets the cap, and the probability of losing load (LOLP). The LOLP is the parameter that determines the slope of the curve. In the last few years before 2021, the ORDC has been triggered primarily at very low prices:

	2017	2018	2019	2020	2021 (through Aug 7)
Average RTORPA ($/MWh)	$ 2.16	$ 1.31	$ 6.37	$ 1.90	$ 12.84
Total non-zero hour-equivalents	1,322	115	1,894	1,390	116

This creates a situation where the market experiences meaningfully high prices only when the system is in or on the brink of an emergency. ORDC adders begin to impact system pricing when there are about 5,500 MW of reserves available as a supply cushion, but the volatility of oscillating between less than $40 per MWh the vast majority of the time and $9,000 per MWh over such a small change in supply cushion levels has resulted in an untenable level of risk. Vistra advises that the ORDC be revised both to reduce the maximum price and to change the shape of the curve to achieve ORDC adders more frequently at lower and mid-level prices. This change can be achieved by modifications to VOLL, the minimum contingency level (MCL) at which the ORDC goes to VOLL, and the shape, slope and terminal value of the ORDC itself (including a step away from the LOLP shape, as that inherently ties market signals to scarcity conditions), as illustrated in this generic example:



By reducing the maximum price and modifying the remaining part of the curve, the ORDC could be used to reduce volatility and improve resiliency, by providing sufficient revenues to maintain and build new thermal generation. Changes to the ORDC are the most expedient tool the Commission has for providing investment signals to the market. Note, however, that this change in ORDC would help only those assets that are available in real-time. Assets at the margin that are not committed or available for real-time operations would not benefit from these modifications to the ORDC and therefore would not solve for the lack of backup resources for extreme weather events like Winter Storm Uri. Therefore it probably makes sense to deliver some of the investment signals through the changes to the ORDC and the rest through ancillary and reliability services that pay for specific reliability attributes.

ORDC is a component of the real-time energy price. Vistra recommends that the Commission avoid market design changes that would cause the energy price to be different for different types of resources because doing so would undermine competition and disrupt the optimization algorithms for dispatching resources (both generation and load resources) efficiently.[3] It would also create significant complications for hedging positions for both generators and load. Finally, we should use all of the State's attributes for new investment and use a competitive set of incentives to stimulate new investment in generation with attributes the market needs for reliability. Therefore, ORDC should be paid to all resources, not just those who commit in the day-ahead market (DAM) or who possess some quality that can meet a seasonal reliability need.

QUESTION 2: Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?

a. If so, how should that minimum commitment be determined?
b. How should that commitment be enforced?

At this point, Vistra is agnostic on the question of whether participation in the DAM should be mandatory, *i.e.*, whether generators would have a compulsory requirement to offer their available capacity. Other U.S. markets do have a must-offer requirement for generators, but only for those who have received payment for their capacity in a separate market. All of those markets also allow voluntary participation in the energy market for any resource that has not received a payment for its capacity. It is not clear that a must-offer requirement in a financial market, like the DAM, would create more certainty in the physical availability of generation in the real-time market (RTM). For thermal generation, Vistra is concerned that it would actually remove flexibility to manage availability, for instance, when a unit experiences a forced outage between the DAM and RTM. That said, if the Commission orders market design changes that provide more certainty and

[3] This issue has been studied extensively in the context of single-clearing price vs. pay-as-bid markets, with the conclusions being that single-clearing price markets provide greater efficiency and avoid perverse behavioral incentives. For example, see the blue ribbon panel report "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing?" by Kahn, Cramton, Porter, and Tabors (January 23, 2001), available at https://core.ac.uk/download/pdf/6960646.pdf.

sufficiency of additional revenues to compensate for taking the capacity value of the resource and are clear that generators can express commitment risks and preferences through price in the DAM, a must-offer in the DAM may be a fair exchange.

Additionally, if there is a move to make the DAM mandatory, it is vital that the full demand-side is participating in the market as well – either through a must-bid requirement, or through demand curves based on ERCOT's load forecasts and reserve supply cushion needs. The ORDC should also exist in the DAM, to support price formation and encourage price convergence with the RTM.

QUESTION 3: *What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.*

The public perception of the appropriate reliability standard is that the Winter Storm Uri experience is not repeated, which sets a high bar given the extreme nature of that event and the efficiency-oriented nature of competitive markets. The Commission should focus on developing ancillary and reliability services that retain and attract generation with attributes that are not fully remunerated through the energy market. Products that should be explored include those that provide additional revenues for generation with firm fuel contracts, fuel storage, and/or dual fuel capability.

Another product that should be considered is a reliability product designed to competitively purchase incremental call options on high heat rate/low capacity factor units that are not economically committed in the DAM or otherwise. ERCOT could procure a quantity of 'standby resource' capacity on a monthly or seasonal basis with the ability to flex up to cover net load needs during tail event scenarios. This kind of product could supplant ERCOT's current practice of using RUC to force uneconomic generation online for conservative additional reserves, while not over-committing resources ahead of their start-up time.

Vistra envisions this product as providing revenue to marginal units that could face retirement otherwise but could have value as backup standby supply for ERCOT to deploy during extreme events, while continuing to rely on the energy and ancillary service markets to drive investment in new resources. Accordingly, resources called on through this approach would necessarily require corresponding changes to counteract price suppression from their utilization. Vistra also views this as a potential competitive solution that could be implemented in lieu of out-of-market solutions, such as the 'Texas Emergency Power Reserve' concept considered during the regular legislative session.

How the Commission allocates costs associated with these new services will undoubtedly be debated. Traditionally such costs are directly assigned to loads, as loads are the ultimate beneficiaries of reliable electric service and costs will ultimately flow directly or indirectly to end-use customers. To the extent that the intermittency of certain resources drives market externalities, though, there may be an economic efficiency argument for such costs to be internalized.

QUESTION 4: Is available residential demand response adequately captured by existing retail electric provider (REP) programs? Do opportunities exist for enhanced residential load response?

REPs are uniquely situated and have a natural incentive to leverage economic demand response within the constraint of residential consumer preferences. Several factors constrain deployable demand response at the residential level, including high relative costs, consumer psychology hurdles, and other variables such as internet connectivity. As such, REPs tend to rely on behavioral demand response much more than deployed demand response.

Residential demand response is a delicate balance. From a behavioral demand response standpoint, the Commission and ERCOT have annually trained REPs for years to not use language that might indicate resource adequacy concerns or the need for conservation unless and until ERCOT issues a conservation notice. For deployable demand response, high hardware and software costs relative to the load capability as well as customer sensitivity to external control over the comfort of their homes – particularly during extreme weather – further limit the available demand reduction from residential customers.

The Commission should note that changes to the ORDC will impact residential demand response incentives as well by providing signals more frequently but with less economic severity, which may further limit the appeal of residential demand response. To the extent the Commission wishes to expand upon deployable residential demand response capabilities for use in grid emergencies, the Commission should consider directing TDUs to reallocate some of their existing program dollars authorized under PURA § 39.905 towards REP-administered demand response programs. There may be emerging opportunities to leverage residential back-up generation as well.

QUESTION 5: *How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?*

There are a few "low-hanging fruit" changes that the Commission could make to improve the reliability benefits of the ERS program. First, prohibit critical loads and generation resource support loads from participating in ERS. Second, prohibit or penalize early deployments, such that ERCOT can count on its contracted ERS load reductions when it actually deploys ERS. Some ERS loads had pre-deployed several days before Winter Storm Uri, such that when ERCOT did deploy ERS as it entered EEA conditions on February 15, only ~400 MW of incremental load reductions showed up relative to more than 800 MW contracted.[4,5] Third, consider prioritizing loads for ERS that are located on under-frequency relay feeders or feeders with critical loads, such that the benefit of the ERS deployment would be maintained and not subsumed if ERCOT were again required to instruct firm load shed. Fourth, similar to the discussion above, expanding weather-sensitive ERS may be a path to retaining and growing residential demand response capabilities while reserving those for true emergencies.

More globally, the Commission should direct ERCOT to adjust the ORDC calculation to account for ERS and other reliability deployments (such as TDU-directed demand response) by decreasing the calculated reserves by deployed contracted ERS MWs. While the ERS deployment impact on system lambda via the Reliability Deployment Price Adder, the impact on the ORDC is not captured, leading to market distortions when ERS is deployed.

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[4] http://www.ercot.com/content/wcm/key_documents_lists/218735/DSWG_May_28_2021_February_Winter_Event_Analysis_Raish.pptx see slide 13.

[5] https://mis.ercot.com/misapp/GetReports.do?reportTypeId=11465&reportTitle=ERS%20Procurement%20Results&showHTMLView=&mimicKey .

QUESTION 6: *How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?*

Vistra supports additional analysis of inertia, voltage support and frequency issues that could be improved by additional market tools, but is not aware of any current issues that would require market design changes.

III. CONCLUSION

Vistra appreciates the opportunity to provide these comments for the Commission's consideration as it works to improve the ERCOT market design. Vistra looks forward to continued participation in this effort.

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Respectfully submitted,

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